India Gas Report

Report prepared for

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BIMST-EC Energy Sector

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Table of contents

Introduction 01

Supply of gas 01

Natural gas production and projections 10

Consumption and demand for gas 12

The gas industry infrastructure.. 18

Import options 21

Natural gas pricing.. 27

Gas industry regulations and outlook..30

Energy sector policies 33

Unconventional sources of gas..44

Strategic alliances in the hydrocarbon sector 47

Introduction

Utilization of natural gas in India started in the early sixties but really picked up after the large western offshore fields - Bombay High and South Bassein - were developed in the late seventies and the late eighties (See Map 1). The early focus was on oil production and as a result a large amount of associated gas from producing oil fields was flared because of a lack of infrastructure and markets. Free gas fields were shut in for the same reason.

In the early 1980's the western offshore gas began to be exploited as a resource instead of being treated as a by-product. The government appointed a number of committees and expert groups to examine the ways in which the gas could be best utilized. The view that emerged was that the optimal use of gas would be in producing fertilizers. Initially there was quite some opposition to the use of gas for power generation but later the idea was accepted. In 1986 work began on the 1700 km HBJ gas transmission line linking the western offshore gas fields with fertilizer and power sector consumers. This resulted in a significant growth in gas production and use through the late 1980's. Flaring from the western offshore has diminished substantially in recent years and is now limited to only technical flaring.

Associated gas has been produced in Assam for over 20 years but flaring has remained at high levels till recently. Free gas fields in Tripura are being used mainly for power generation. Some associated gas is being produced in Arunachal Pradesh but utilization by a proposed gas-to-liquid plant is yet to start. Consequently, this gas has to be flared.

Gujarat uses more gas than any other state in India. In addition to the gas produced in the state, consumers in the state also use a part of the western offshore gas. Andhra Pradesh, Tamil Nadu and Rajasthan are the other states that produce gas. The gas produced off the coast of Andhra Pradesh in the Ravva field is being utilized since 1997. Currently around 75% of India's gas is produced from the western offshore fields but this production is now in decline.

Supply of gas

Sedimentary basins in India

Sedimentary basins in India are spread over 1.39 million square kilometers onshore and 0.4 million square kilometers offshore. An additional 1.35 million sq km is in deep water areas.

The major basins are found along the east and west coasts, through the Assam fold belt, onshore Gujarat, Rajasthan, the Ganges Valley, Bengal, and the Vindhyan and Deccan synclines in central west India. Other smaller basins are found scattered across the sub-continent. It has been estimated that only some 33% of this area has been explored. However the explored area includes all the areas which are at present considered to be the geologically most prospective.

The various basins have been categorized according the prospectivity; Category I consists of producing basins, while Categories II to IV are basins with reducing prospectivity. The Category I basins include:

- Cambay Basin, Gujarat
- Bombay Offshore
- Cauvery Basin
- Krishna-Godavari Basin
- Assam Shelf/Assam Arakan Fold Belt

Early E&P activities (during the 1960's and 1970's) were concentrated in Category I basins but since the early 1980's efforts were increased into unexplored areas, in particular offshore acreage.

Gas reserves

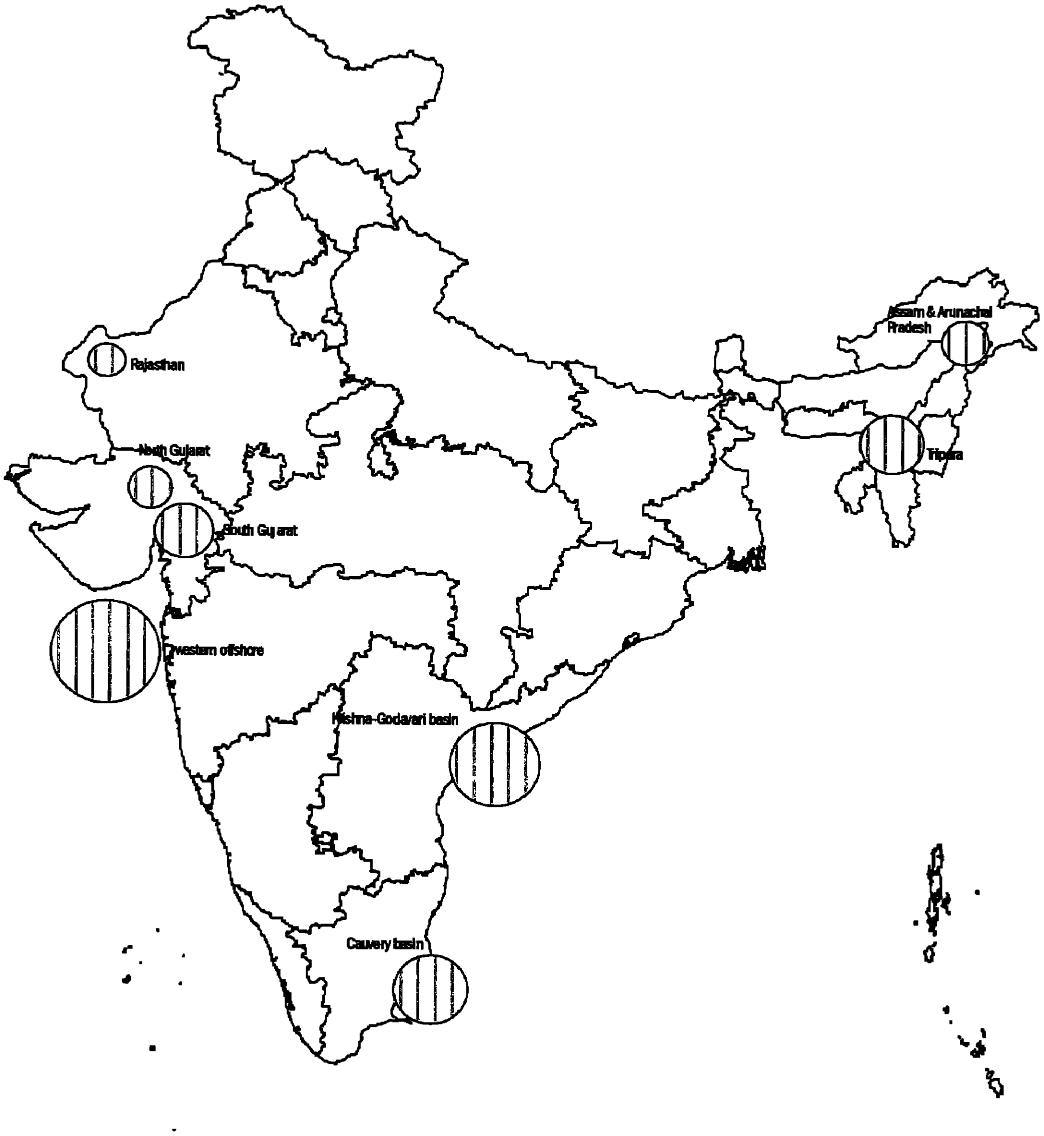
Estimates of gas reserves based on figures from the Ministry of Petroleum and Natural Gas (MoPNG) indicate that the reserve reached 736 bcm in 1992 but declined to 648 bcm by 1999.

Table 1 State-wise balance recoverable reserves of natural gas: 1990 to 1999

Natural gas reserves (bcm)	1990	1991	1992	1993	1994	1995	1996	1997	1998
Onshore									
Gujarat	92.6	93.4	94	92.9	92.1	89.9	88.0	86.5	84.2
Assam	135.5	151.7	160.5	156.1	156.2	159.2	173.8	182.5	187.7
Rajasthan	1.0	1.2	1.3	3.8	3.8	4.1	4.5	4.5	4.4
Total onshore	229.1	246.3	255.7	252.8	252.1	253.2	266.2	273.8	276.5
Offshore									
Western	457.4	483.5	479.8	465.1	454.6	406.5	377.2	418	398
Total	686.5	729.8	735.6	717.9	706.7	659.7	643.3	692.1	674.8

Source. TERI Yearbook 2000/2001

The bulk of the proven reserves (>60%) is located on the western offshore region, the remainder mostly located in North East India (24%) and Gujarat (13%). The reserve to production ratio for 1999 is 23.5. However, the effective ratio is closer to 17 since a large portion of the gas occurs in the gas caps in oil fields, which cannot be produced till the oil is depleted.



Map 1 Major gas producing areas

The recoverable gas reserves base in India has grown from 185 bcm in 1975 to 736 bcm in 1992. Since 1992 the reserves figure has declined to 648 bcm by 1999. For the period from 1975 through to 1980 gas reserves were added at a much greater rate than gas was produced, the recoverable reserves in 1980 was 411 bcm as against 185 bcm in 1975. The net addition to reserves continued through the mid 1980's at a lower rate and increased through to 1992, by which time recoverable reserves were at 736 bcm. Since 1992 there has been a slow net depletion from the reserves figures, with the decline increasing in 1995.

Table 2 Life of reserves of natural gas 1990-1999

Year	Recoverable Reserves (bcm)	Production (bcm)	Life of Reserves *(yrs current prodn.)
1990	730	18.0	39.3
1991	736	18.7	39.4
1992/93	718	18.1	39.7
1993/94	707	18.3	38.6
1994/95	660	19.4	34.0
1995/96	640	22.3	28.7
1996/97	692	22.7	30.5
1997/98	675	26.4	25.6
1998/99	648	27.4	23.6

Source. TERI Yearbook 2000/2001

Exploration prospects and activity

Only 33% of the total 3.14 million sq.km sedimentary area of the country has been explored upto a moderate level. A three pronged strategy for exploration has been pursued since the early 1990s.

- Intensive exploration in category-1 basins for conversion of resources to proven reserves
- Selective but focussed exploration in Category II and other frontier onland and shallow water basins
- Exploration and production from deep water areas (resources of deep water areas are expected to be 11 billion tonnes, and is expected to provide 2-3 billion tonnes of oil and oil equivalent gas in the next 25 years)

Exploration prospects

Most of the major oil and gas finds in India came during a phase of heavy exploration in the 1970's. During this period all of the known major fields in India were identified, although in many cases development occurred much later. There has been a net addition to reserves until the 1990's. However, there have been few important finds in the last decade.

The three main producing basins in the country, the western offshore region, the Cambay basin in Gujarat, and Upper Assam region, are in the mature phase of exploration and with the exception of Assam, future finds in these areas are not likely to be large in size.

The more recently discovered fields of Cauvery and Krishna Godavari off the east coast of India are relatively small but Krishna Godavari is believed to hold a promise for development.

Exploration activity

Success in oil and gas exploration in India has come in cycles. There have been brilliant discoveries such as the Bombay High and other western offshore fields and there have been periods over which the same amount of physical effort did not produce any appreciable result. By and large, exploration has been in the hands of National Oil Companies (NOCs) - Oil and Natural Gas Corporation Ltd., (ONGC) and Oil India Limited (OIL). Being commercial organizations, their strategy has been to concentrate in areas near producing fields.

The 26 sedimentary basins in India include six such category I basins that have been moderately well explored. The rest of the basins have not been explored at all well. The sedimentary basins in India add up to 3.14 million square km in area. Of this, 67.3% is unexplored. Of the balance, about half is moderately to well explored, and the other half is poorly explored. The exploratory drilling intensity is low compared to that of USA.

ONGC and OIL have been known as good finders. However, as they faced the challenge of exploring more difficult areas and the deep waters, the technology gap became critical. According to experts, this gap between the best globally available technology and that used by ONGC is serious and could grow larger. Reserve accretion of oil and gas during the Seventh Five-year Plan (1987□92) exceeded the depletion and the reserves to production (R/P) ratio went up even as the production increased. The Eighth Five-year Plan period (1992□97) started on a poor note. The accretion in the first three years was far short of target and the government decided to launch the accelerated program for exploration (APEX), which had a number of components including:

- A national seismic grid.
- Exploration in frontier areas and deep waters

The Eighth plan outlay was also suitably enhanced. The idea behind the national seismic grid was to extend the available seismic data to the areas not yet covered and to upgrade the data quality. Attempts to involve the private sector in seismic surveys through bidding rounds for speculative surveys were not successful. However, joint venture speculative surveys with participation of the Directorate General of Hydrocarbons (DGH) have been more successful. These have opened up 0.4 million-sq. km. DGH has also covered the entire Indian continental shelf up to a depth of 3000 metres through satellite gravity surveys.

In spite of this mid-course correction, reserve accretion targets were not met by the end of the plan period. This was among the factors, which redirected attention on supplementing these exploration efforts by bringing in the private sector. Exploration bidding rounds started in 1979, far ahead of the economic reforms of the 1990s, but the early rounds were not successful. The first four rounds took twelve years to come (1979-91). The next five rounds came in two years (1994-95) and succeeded in generating some interest in the international oil industry. To increase this interest, government decided to award some small and medium sized fields for development in the private and joint sectors respectively. An innovation was also introduced in the ninth round - known as the JV round – to reduce the risk for the private investors by associating ONGC/OIL as partners in these exploration ventures. However, the rigid decision making structures of these NOCs created problems of compatibility and reduced the attractiveness of this innovation. The number of blocks advertised before the launch of the New Exploration Licensing Policy (NELP) and the bids received in the various rounds were as below:

Table 3 Exploration blocks offered and bids received

Round	Year	Blocks offered	Bids received
I	1979	32	4
II	1982	50	nil
III	1986	27	13
IV	1991	72	24
V	1993	45	15
VI	1994	46	20
VII	1994	45	12
VIII	1994	34	38
JV	1995	34	22

The result of this effort has been that 35 exploration blocks and 30 discovered fields have been awarded to the private sector. Work is in progress in 22 exploration blocks and contracts for some more blocks would be signed soon. Five medium and thirteen small fields are under development, some of which are already producing oil/gas. The total investment brought into the sector, mostly in producing fields, so far exceeds US dollars 1 billion. Production of crude oil and natural gas from these fields has increased over the years to amount to about 10% of the total production. The bulk of the reserve accretion through these efforts has taken place around the previously discovered fields. Although these results are by no means insignificant, there is general agreement that these have not met expectations and a number of reasons are cited for the disappointing results.

There was a perception that the blocks with better prospects were reserved for the NOCs and only the high-risk areas were offered to the private investors. The seismic data provided was inadequate in most cases in addition to being old and expensive. The NOCs continued to hold on to the blocks they were awarded on a nomination basis. They also played a decisive role in the delineation of the blocks to be offered in the bidding rounds. Though it was recommended that, where feasible, an exploration block should include a producing field or an area with oil/gas finds, there were instances where this was not done and the producing areas were left out of the blocks. There were instances of a block being advertised and later withdrawn at the instance of a NOC. These factors reduced the commercial attractiveness of the blocks offered. The incentive structure was designed after a study of practices followed by other countries such as China and Indonesia. Many potential bidders were, however, of the opinion that better incentives were necessary in India to make up for the higher perceived risks.

The third factor, a very important one, was the delays in policy making and implementation of the exploration sector policies. The award of production sharing contracts (PSCs) requires clearance from several ministries, leading to inordinate delay. Though there is an empowered committee of secretaries, it has had limited success in cutting through red tape. While it should normally take a few months to award these contracts after the receipt of bids, in practice, it took 2-3 years. Further, the awards were followed by lengthy negotiations prior to signing of the contract. Even after the contract was signed, many approvals, including the all important exploration license, were required. These also took time to come through.

The NELP

With a view to removing these shortcomings, a New Exploration Licensing Policy (NELP) was formulated by the government in 1997-98 to provide a level playing field in which all parties could compete on equal terms for the award of exploration acreage. The salient features of the NELP are:

- NOC's to compete for acreages
- Fiscal stability provision in the contract
- Model Production Sharing Contract to aid contract negotiation
- Petroleum tax guide to help investors
- Possibility of seismic option in the first phase of the exploration period

Some of the improvements in the fiscal and contractual terms are:

- No payment of signature, discovery or production bonus
- No customs duty on imports required for petroleum operations
- No minimum expenditure commitment during the exploration period
- No mandatory state participation/carried interest by NOCs.
- Freedom to sell crude oil and natural gas in domestic market at market related prices
- Biddable cost recovery limit up to 100%
- Biddable sharing of profit petroleum based on pre-tax investment multiple achieved
- No cess on crude oil production
- Royalty payment for crude oil on ad-valorem basis
  - 12.5% for onland areas
  - 10% for offshore areas
- Royalty on deep water areas(beyond 400m bathymetry)
  - 5% for first seven years after commencement of commercial production
- Option to amortise exploration and drilling expenditures over a period of 10 years from first commercial production
- Contribution to site restoration fund fully deductible in same year for income tax
- Liberal depreciation provisions making companies eligible for further tax adjustments
- Infrastructure status
  - 7 years tax holiday from commencement of production
- Conciliation and Arbitration Act, 1996, which is based on UNCITRAL model made applicable.

The companies are required to bid for

- Work programme commitment
- Profit petroleum share expected by the contractor at various levels of pre-tax multiple of investments

- Percentage of annual production sought to be allocated towards cost recovery

The main bid evaluation criteria are:

- Technical capability of the bidding company / consortium
- Operatorship experience
- Financial capability of the bidding company / consortium
- Work Programme
- Profit sharing offered by the bidders/s along with proposed cost recovery limit

The first bidding round was launched in 1999 in which 48 blocks were offered. For the first time these included deep sea blocks. In spite of the low oil prices prevailing at the time, the response was satisfactory. Of the 27 blocks bid for, 25 have been awarded and 24 contracts have been signed. The processing of the bids and the contract negotiations have been fast compared to earlier rounds. An investment of $250 has been committed by the awardees in the first phase of exploration. Expectations of striking large oil and gas reserves are high, especially in the Krishna Godavari basin.

The second bidding round was launched in December 2000.The government is reportedly considering the introduction of continuous bidding but no announcements have been made as to when this would be introduced.

Exploration for Coal Bed Methane

India is endowed with rich deposits of coal and lignite. The bulk of the coal resources of about 206 billion tonnes is in the Gondwana basins of Peninsular India. Large deposits of lignite are known to occur in Tamil Nadu, Gujarat and Rajasthan. The proven reserves of coal and lignite in the country is estimated at 100 billion tonnes.

These coal and lignite seams contain varying amounts of methane depending on the rank of the carbonaceous matter, the depth of burial and the geotectonic setting of the basins. The commercial production of such methane, better known as Coal Bed Methane (CBM) is a proven technology and has added to the natural gas production of some countries.

The government wishes to involve both the public and the private sectors in developing these resources. The exploration and development is proposed to be spread over four phases:

Phase I	Exploration	3 years
Phase II A	Pilot Assessment	3 years
Phase II B	Market Confirmation	2 years
Phase III	Development	5 years
Phase IV	Production	25 years

The important parameters which have been kept in view in delineating the exploration blocks are as below:

- Occurrence of high rank coals
- Development of thick coal seams.
- High gas content of the seam.
- Presence of well developed cleats/fractures in the seams to induce higher permeability.
- Deep burial of the seams beyond 600 m depth
- Evidence of emission of methane gas in adjoining coal mines/boreholes.

Keeping the above parameters in view, several blocks in the Gondwana basins have been delineated in the first instance for exploration and exploitation of CBM. These blocks are located in Raniganj and Birbhum (West Bengal), Jharia, Bokaro and North Karanpura (Bihar), and Sohagpur and Satpura (Madhya Pradesh) basins. Preliminary estimates suggest that these blocks could contain about 13 TCF (368 BCM) of methane gas.

The suggested fiscal & contractual terms are as below:

- There will be no Government participation in the project.
- Allotment of blocks would be through a system of global bidding.
- Exploration and development will be under concessions and not under PSCs.
- No signature bonus.
- No Customs duty.
- The project will enjoy the benefits of an Infrastructure status which provides for a 7 year tax holiday from the date of commencement of production.
- Base rate of 10% ad-valorem royalty payable to the State Governments.
- Additional production level payments are biddable. Payments on sliding scale for every 0.5 MMSCMD of incremental gas production after reaching the production of 1.0 MMSCMD.
- Nominal commercial bonus of US$ 0.3 million on declaration of commercial assessment.
- Liberal depreciation provisions.

- Contribution to site restoration fund.
- Model contract to be put in place.
- New Petroleum Tax Guide to facilitate investors
- Freedom to sell gas in the domestic market.
- Provision for 100% cost recovery.

Going by the recent announcements by the government, the first round of bidding for CBM blocks could be expected in the next three months.

Natural gas production and projections

Natural gas production

Natural Gas production in India has undergone a major growth in the last 30 years, growing from a production rate of 1.4 bcm in 1975 to 27.4 bcm in 1999.

There are five major gas producing areas in India today (See Map 1):

- The Western Offshore region which extends from offshore Bombay to Gujarat
- Gujarat, where there are two producing areas
- The Krishna Godavari basin
- The Cauvery basin
- Assam and Arunachal Pradesh

The current output is heavily concentrated in the western offshore fields which produced 16.5 bcm of the total of 22.3 bcm of gas produced in 1995/96. Onshor Gujarat fields were the other major producing areas with 2.9 bcm in 1997. The other producing areas, Assam, Tripura, Cauvery Basin, Krishna-Godavari contributed 2.8 bcm in 1995/96, although a significant percentage of this gas was flared.

Table 4 Production of natural gas: 1990 to 1999

Natural gas production (MMCMD)	1990/ 1991	1991/ 1992	1992/ 1993	1993/ 1994	1994/ 1995	1995/ 1996	1996/ 1997	1997/ 1998	1998/ 1999	1999[b]
Onshore										
Gujarat	1696	1698	1946	2166	2462	2878	2932	3115	3166	2354
Assam / Nagaland	2011	31	52	47	1909	1880	1941	2018	2055	1563
Arunachal Pradesh	29	271[a]	676[a]	788[a]	37	32	23	24	24	17
Tripura	70	-	-	-	97	131	154	196	307	268
Tamil Nadu	64	-	-	-	98	117	92	95	107	98
Andhra Pradesh	46	-	-	-	640	679	799	1022	1218	1027
Rajasthan	-	-	-	-	-	12	10	148	163	109
Total	3916	4251	4708	4979	5243	5729	5951	6618	7040	5436
Offshore										
ONGC	14082	14394	13352	13356	14138	16579	16794	18102	17514	13271
Private / Joint venture companies	-	-	-	-	-	331	510	1681	2874	2641
Grand Total	17998	18645	18060	18335	19381	22639	23255	26401	27428	21348

[a] Includes Tripura, Tamil Nadu, and Andhra Pradesh

[b] April-December 1999

Source. TERI Yearbook 2000/2001

Historically, production levels have fallen short of targets set in five-year plans. Under the Eighth five-year plan production fell short by 19% of the target. This was largely the result of the lower than expected oil production rates due to a variety of technical reasons; deferment of projects, reservoir management rectification's, reduction in gas-to-oil ratios, environmental problems etc.

The flaring of gas in India has been a major issue for a large number of years with large amounts of natural gas being flared due to the lack of downstream offtake. In the 1980's the flaring of gas was at levels of 35%-40% of gross production. There has been a significant effort to utilize the gas in the last 15 years and at present flaring is down practically to the technically minimum level.

Future gas production projections

ONGC draws up long term profiles of gas production every year. These are based on development plans already finalized as well as on anticipation of future discoveries. Current projections show that the total gas production would rise from 73 MMCMD in 1998 to 80 MMCMD in 2001. Thereafter the production would decline steadily until the Bombay High gas cap is brought into production. This is expected between 2015 and 2020.

The declining production profile coupled with the projection of rising demand shows a widening demand-supply gap. The implications of this gap are that exploration efforts need to be stepped up and the feasibility of importing gas from the neighbouring countries examined seriously. The initiatives for exploration have been described earlier. A number of options for importing gas through pipelines and as LNG have been examined or are being examined, as is the prospect of utilizing domestic coal-bed methane reserves.

Three scenarios for gas supplies as presented in the Natural Gas Development Masterplan are as follows:

- As given scenario: which extrapolates trends reflected in the given projections up to 2020.
- Optimistic scenario: that allows for increased production from more prospective fields and sustained production from some mature fields. Contribution from CBM is also included.
- Pessimistic scenario: which shows progressive decline of producing and existing fields with no significant new developments.

Table 5 Future gas supply scenarios (MMCMD)

Scenario	2002	2007	2012	2020
As given	69.89	58.57	45.22	36.31
Optimistic	69.89	63.76*	78.50*	83.94*
Pessimistic	69.89	54.57	32.83	27.92

* Includes production from new fields and CBM

Consumption and demand for gas

Although the use of natural gas has increased rapidly, natural gas accounts for only around 7%-8% of the primary energy in use. Till the late 1980's the demand lagged behind the supply mainly because of lack of infrastructure. In the 90's, the demand has exceeded supply. In the circumstances, the government has been allocating gas through the Gas Linkage Committee. Till 1992, GAIL had a system of registering gas demand. A demand of 260 MMCMD was registered with GAIL. Not much should be read into this number, as this demand was not linked to a particular gas price. Moreover, there was no commitment on behalf of the units registering demand and no effort was made to determine the seriousness or the financial capability of these units.

On the other hand, gas allocations were made after careful assessment of the projects for which gas was sought and are, to that extent, a better indicator of the "true" demand. The allocations made so far are shown in the table below:

Table 6 Statewise / sectorwise gas allocations (MMCMD)

States	Fertilizer	Power	Sp. Iron	Others	Int.use/shrinkage	G. Total
Andhra Pradesh	2.14	6.14		0.40		8.67
Assam	0.45	1.02		8.94	0.35	10.76
Delhi		2.60		0.48		3.08
Gujarat	4.21	8.24	3.11	8.39	2.07	26.02
Haryana		1.95		0.80		2.75
Madhya Pradesh	3.22				0.98	4.20
Maharashtra	5.70	6.00	2.65	2.80	0.45	17.60
Pondicherry		0.20		0.004		0.20
Rajasthan	1.76	2.31				4.07
Tamil Nadu		2.01	0.01	0.15		2.17
Tripura		4.65		0.15		4.80
Uttar Pradesh	8.80	5.36	0.35	2.28	2.63	19.42
Total	26.28	40.47	6.12	24.39	6.48	103.74

The power and fertilizer sectors have been allocated most of the gas. These two sectors together consume about 80% of the gas today. The sponge iron units consume another 10%. The balance goes to industrial units where it replaces mostly fuel oil but some LPG also. Gas is also supplied to the residential and the commercial sectors in Mumbai, Delhi and a few towns of Gujarat, Assam and Tripura. This gas is used for cooking only, as space heating is not required. The daily requirement of households is only around 1 cu meter. With such low requirements and the subsidy on domestic LPG, the demand from this sector will continue to be low. The use of CNG in lieu of petrol has been popular in Mumbai and is now picking up in Delhi.

The requirement of gas over the time horizon up to 2025 would depend upon a number of factors and their complex inter-relationship. The growth in energy consumption would depend upon the growth of population and of GDP, the structural changes in GDP, the growth of industrial and agricultural sectors, energy pricing and tariffs and the success of energy conservation measures based on the need to contain damage to the environment.

So far as the future gas demand is concerned, an analysis of the dynamics in the power and fertilizer sectors needs to be undertaken to decide the role that gas will play in these sectors. In this context the following projections are important:

- The food-grain production, by 2011-12, has been projected to reach a level of 337 MT as against 200 MT at present. This would obviously push the utilization of fertilizers and fertilizer consumption has been projected to increase from 16 MMT in 1998/99 to about 46 MMT by 2011-12.

- Urea would remain a major constituent of fertilizers in use and over the next 10-12 years a many fold increase in urea production capacity would be required.
- Various estimates for installed generation capacity in 2011-12 show the requirement for adding substantial capacity in the next fifteen years.

Over the past many years a number of gas demand projections have been made by various agencies. Broadly two approaches were adopted in estimating the long-term gas demand i.e. (i) end use method and (ii) demand projections based on macro economic parameters.

Table 7 Demand estimates as by various agencies (MMCMD)

Agency	1999-00	2003/4	2004/5	2005/6	2007/8	2009/10	2012/13	20
Expert group (1994) MOP & NG	143		183			285		
TERI's estimate (1994)	-	-	-	258 293	-	-	-	
World Bank Paper (April 1995)	-	200	-	-	-	-	-	
Gas Master Plan (1999-ADB's TA)		121	-	-	185	208	263	

The Expert Group had considered that it would be cheaper to import fertilizers and therefore, the fertilizer sector may not need additional gas. The gas demand, thus worked out, relates predominantly to the power and the industrial sectors. The estimates made by TERI in 1994 were based on macro economic parameters assuming certain GDP growth rates. The projections made in the Masterplan are pre-dominantly those for the power sector.

Demand projections

Sales to the fertilizer sector dominate the consumption in the country, followed by sales to the power sector. These two sectors are expected to dominate the demand pattern in the future too.

Table 8 Average supply of gas in 1998/99 (MMCMD)

	Fertilizer	Power	Sponge Iron	Other	Total
GAIL					
Sales	23.59	21.94	3.46	6.09	55.07
Internal Consumption					1.20
LPG Shrinkage					1.16
Total Supply by GAIL					57.40
ONGC (Direct Marketing)		0.15			0.15
Assam Gas Company	0.71	1.41		0.58	2.70
All India	24.30	23.50	3.46	6.67	60.3

Power

The power and fertilizer sectors can be expected to form the key sectors in forecasting the demand for gas in India, both because of their role as anchor customers and in their size and expected growth.

The approach adopted in the Natural Gas Development Masterplan for estimating gas demand originating in the power sector is to determine the competitiveness of gas at different locations using the imputed value approach. The logic behind the imputed value calculations is to equalize the cost of generation for a given technology (in this case gas based CCGT) with the cost of generation from other alternative technologies, at a particular location.

Cost of generation comprises the capital cost, the fixed O&M cost and the fuel cost. The capital and fixed O&M costs for gas-based generation are netted out from the total cost of generation for each alternative technology to determine the imputed gas value (per unit sent out). These imputed gas values indicate the maximum charge for gas to make it competitive with alternative fuels. The lowest imputed value indicates the competitive price of gas at a particular location.

Assessment of gas demand for the power sector for the years 2002, 2007 and 2012 is based on identification of planned thermal capacity additions. These are sourced from:

- CEA's Fourth National Power Plan 1997-2012 (proposed thermal plants include coal-based, gas-based and naphtha-based plants).
- Ministry of Power's list of private power producers

2020 and 2025

For the year 2020 there are no official projections for capacity additions and electricity demand. Electricity generation for 2020 and 2025 is projected using an electricity-GDP elasticity (this indicates the percentage change in electricity generation for a percentage change in GDP). The projected growth rate for GDP and the elasticity are given below. The electricity-GDP elasticity reveals a declining trend and this has been projected. It is assumed that of the total electricity generated, 70 percent will be thermal power, the balance being generated by hydro and nuclear plants.

Table 9 Electricity-GDP elasticity and GDP growth rates

Year	Electricity-GDP elasticity	Annual GDP growth (%)
1970-1980	2.81	3.1
1980-1990	1.91	5.6
1990-1995	1.61	4.9
1995-2000	1.33	6.8
2000-2005	1.10	6.9
2005-2010	0.90	7.1
2010-2020	0.75	6.8
2020-2025	0.75	6.0

In light of the above, the gas-based capacity additions and resultant gas based demand are estimated as follows:

Table 10 Projections of gas demand: Power Sector

	1999	2002	2007	2012	2025
Scenario I: Demand at value of gas about $ 4/MMBtu					
Capacity (MW)	8234.6	10307	17190	23298	40929
Gas demand* (MMCM)	11649	14581	24319	32960	57903
Gas demand (MMCMD)	32	40	67	90	159
Scenario 2: Demand at value of gas about $ 3/MMbtu					
Capacity (MW)	8234.6	17192	30761	43449	84665
Gas demand* (MMCM)	11649	24322	43518	61468	119779
Gas demand (MMCMD)	32	67	119	168	328

The above calculations assume that 0.19 cu. mt of gas is required for 1kWh and also assume a plant load factor of 85%.

Fertilizer sector

The demand of gas for fertilizer production is estimated to grow to 131 MMCMD in 2025. These projections made by the Fertilizer Association of India are based on per capita requirement of food grains, fertilizers required to attain the necessary production, the share of urea to sustain this yield (excluding imports), and consequently, the gas required to produce this urea. The Fertilizer Association of India has argued that additional capacity would have to be set up on grounds of food security even if the international urea prices are low. This is because the international prices depend on the purchases made by India and China and the price increases whenever these countries enter the market for large purchases.

Assuming that 80% of the capacity in 2006/07 and beyond would be gas based and the remaining naphtha based, the potential demand for gas in this sector would be as follows.

	1999	2002	2007	2012	2025
Gas demand (MMCMD)	36	54	64	83	105

Other sectors

There is a range of other sectors, including industry, commercial and households, which will demand gas.

Planning Commission has made the following estimates for the other sectors

	2001-02	2006-07	2011-12
Household sector	262	304	347
Industrial sector	3920	4558	5197
Total - MMCM	4182	4862	5544
Total - MMCMD	11	13	15

However, the demand from these sectors is likely to be incremental to that of the anchor customers viz. power and fertilizers. Accordingly, the estimates of power and fertilizer demand can be suitably augmented to project total demand for gas. It can be assumed that the other sectors would account for 20% of the total demand in 2002 and thereafter. This assumption is based on the current share of 17% for this category (including sponge iron) in the total volume of gas sold. Accordingly, we arrive at the following aggregate demand:

Table 11 Total Gas Demand (MMCMD)

	1998/99*	2001/02	2006/07	2011/12	2024/25
Power[a]					
Scenario I	22	40	67	90	153
Scenario 2	22	67	119	168	208
Fertilizers[b]	24	54	66	83	105
Others[c]					
Scenario 1	9	23	33	43	64
Scenario 2	9	30	46	63	78

	1998/99*	2001/02	2006/07	2011/12	2024/25
Total					
Scenario 1	55	117	166	216	322
Scenario 2	55	151	231	313	391

*: Actual sales

[a] Modified TERI's projections from the Masterplan

[b]: Based on submissions made by FAI to the Sub-group and other official projections

[c]: Estimates based on a pro-rata assumption

Demand-supply balance

The demand -supply balance based on the above demand and supply projections is provided below:

Table 12 Gas deficit (MMCMD)

	2002	2007	2012	2025*
Demand Scenario 1	117	166	216	322
Supply as given scenario	70	58	45	36
Supply Optimistic scenario	70	64	78	84
Gap	47	108	171	286
	47	102	138	238
Demand Scenario 2	151	231	313	391
Supply As given scenario	70	58	45	36
Supply Optimistic scenario	70	64	78	84
Gap	81	173	268	355
	81	167	235	307

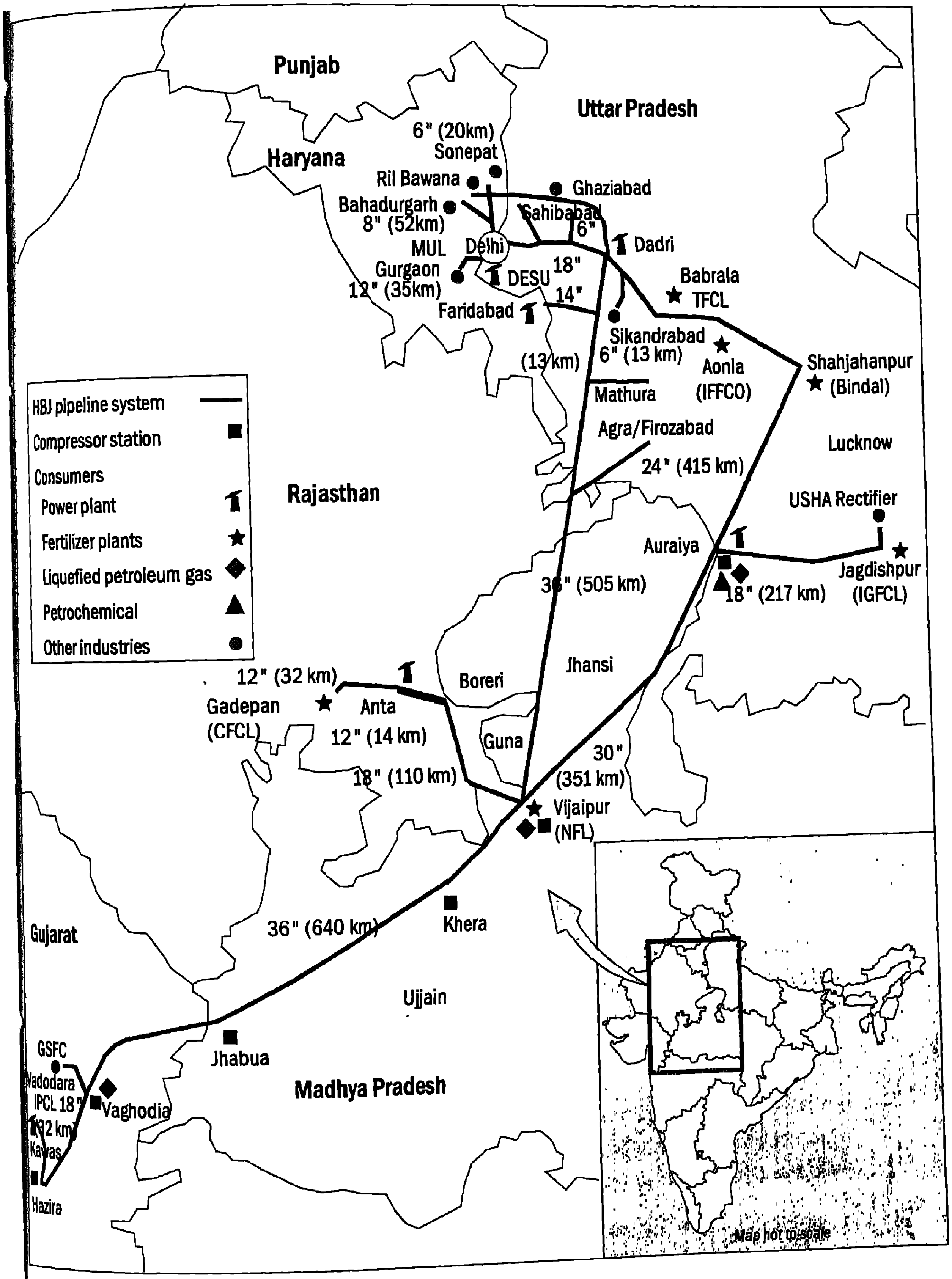
*: In the absence of supply projections for 2025, it is assumed that gas supply in 2025 is the same as those for 2020

The gas industry infrastructure

Transmission

Currently in India the gas infrastructure can handle the production and transportation of about 100 MMCMD of gas. Most of the transmission infrastructure is installed in the north west of India for transportation of gas to shore from the western offshore fields and the transmission of this gas to end users. By far the largest of the transmission systems is the HBJ (Hazira-Bijaipur-Jagdishpur) line. This pipeline (2,300 km) transverses the states of Gujarat, Madhya Pradesh, Rajasthan, Uttar Pradesh, and Haryana (See Map 2).

In addition to the HBJ pipeline, there also exist regional gas grids of varying sizes in the states of Gujarat, Andhra Pradesh, Assam, Maharashtra, Rajasthan, Tamil Nadu and Tripura (See Map 3). These regional pipelines (about 725 km)



Map 2 HBJ (Hazira-Bijapur-Jagdishpur) transmission system

were constructed and operated by ONGC, but with the commissioning of the HBJ pipeline in the late eighties, ownership and operation of these gas grids were passed on to GAIL.

Table 13 Major pipelines

Network	States	Length in Km
HBJ and ex-Hazira	Gujarat, MP, Rajasthan, UP, Haryana, Delhi	2688
South	Andhra Pradesh, Tamil Nadu, Pondicherry	395
Gujarat	Gujarat, Rajasthan	743
North-East	Assam, Tripura	63
Maharashtra	Maharashtra	128
Total		4017

The HBJ pipeline

The capacity of HBJ has recently been expanded from 18.2 MMCMD to 33.4 MMCMD. The present grid capacity is based on the gas availability from the producing areas as well as the outlook for future gas production. The capacity of HBJ is proposed to be further expanded to 60 MMCMD. GAIL has recently announced plans to install new pipelines in Andhra Pradesh in view of the recent gas finds in the area.

Distribution

Demand for gas in the residential sector is low in India as there is no requirement for space heating. The gas is used only for cooking and the requirement per household does not exceed 1 cu. mtr. a day. Residential distribution has succeeded only where supported by industrial and commercial offtake. Brief particulars of such systems are given below.

Baroda Municipal Corporation (Baroda)

This is an old system started in the 1970's. It caters to around 50,000 domestic and commercial customers. The gas allocated to the project is 0.06 MMCMD on firm and 0.02 MMCMD of fallback basis.

Gujarat Gas Company (Gujarat)

This company runs two projects, one in Ankleshwar/Bharuch and the other one in Surat. The gas allocations are 0.17 MMCMD and 0.30 MMCMD respectively. About 0.08 MMCMD is supplied to domestic consumers in Surat, the rest being used by small industrial units.

The company also has a gas purchase commitment of 0.7 MMCMD from Gujarat State Petroleum Corporation.

Mahanagar Gas Limited (Bombay City)

This project is being implemented by a joint venture between GAIL and British Gas, called Mahanagar Gas Ltd. The present customer population is about 42,000 besides commercial/industrial units. It also supplies gas to 11,000 natural gas vehicles in Mumbai, including buses. Successful trials have been conducted on autorickshaws as well. The project cost is around Rs. 420 crores. And the gas allocated is 1.5 MMCMD.

Indraprastha Gas Limited (New Delhi)

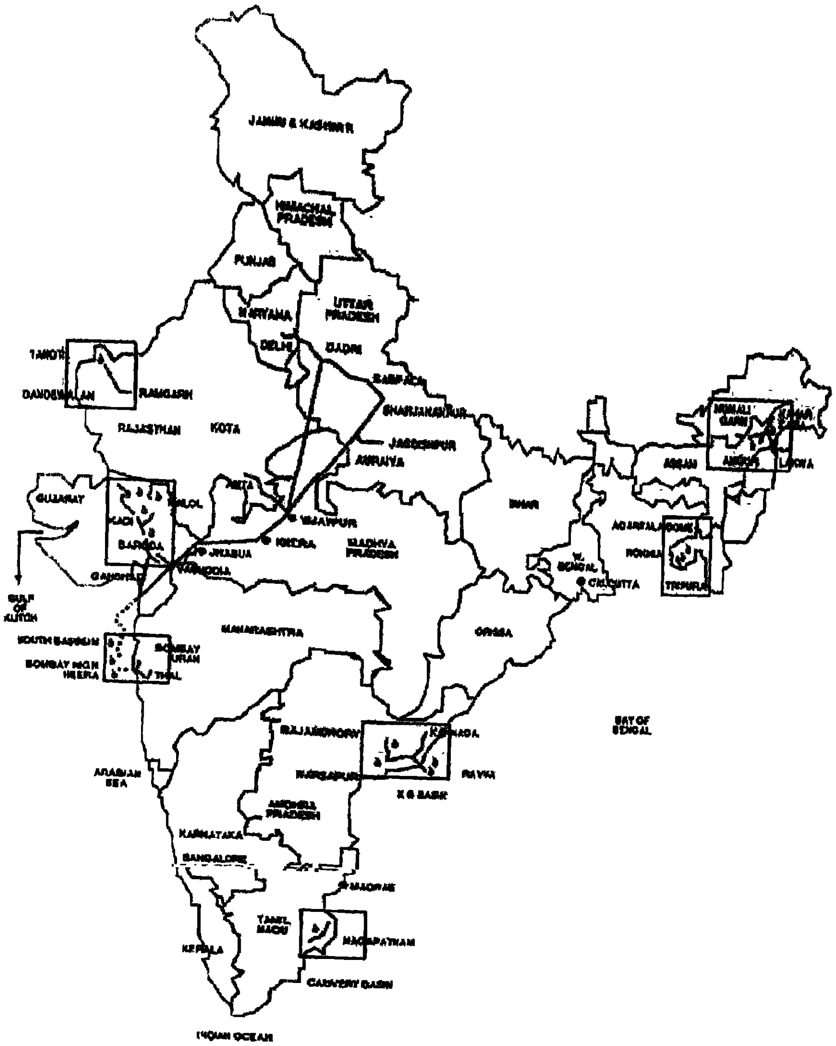
This project is being implemented by a joint venture between GAIL and BPCL. An allocation of 0.33 MMCMD has been made for the project for a target consumer population of around 200,000. For CNG an allocation of 0.15 MMCMD has been made. At present about 1000 domestic consumers are being supplied gas along with a number of CNG buses, taxis and autorickshaws.

GAIL (Agra-Ferozabad)

This project was taken up by GAIL to supply gas to the industry around the Taj Mahal to protect it from harmful emissions. At present 25 consumers in Agra and 80 in Ferozabad are drawing gas. Ultimately around 182 units will be served by the project for which, an allocation of 0.6 MMCMD has been made and contracts have been signed.

Expansion of infrastructure and requirement of funds

The requirement of major gas sector infrastructure would depend upon the mix of modes of gas imports i.e., LNG and pipeline gas. The investments required on gas infrastructure development would be considerably higher in case of LNG import projects, due to the need to set up expensive terminals. Typically, a LNG import terminal of 5 MMTPA capacity would require an investment of the order of US$400 to 500 million depending upon the site characteristics. However, the expansion of such terminals can be less expensive. If one considers that most of the future gas requirements would come from import of LNG, about 6 to 7 LNG terminals can be considered operational between now and 2025. These terminals, at present date costing, would need an investment of about US$3.5 billion.



Map 3 Gas pipeline infrastructure

The HBJ pipeline system would be further expanded to nearly double its existing capacity for marketing of LNG imported into the western region. This would require an investment of about US$1.5 billion. New pipelines may require an investment of another US$2 billion. If gas from Bangladesh and Iran is imported by pipeline, the investment within India for marketing such gas from the land fall point could be another US $ 2 billion. Thus, in the next 20 to 25 years time the gas sector may need an investment of US $ 10 billion on setting up of LNG terminals, trunk gas pipelines and necessary compression facilities for transmission and distribution of gas to the markets.

Such large investments would require the participation of the private sector, both domestic and foreign. This could be possible if regulatory reforms are initiated immediately. Since the bulk of the gas would be used in the power and the fertiliser sectors, regulatory reforms in these sectors would be equally important.

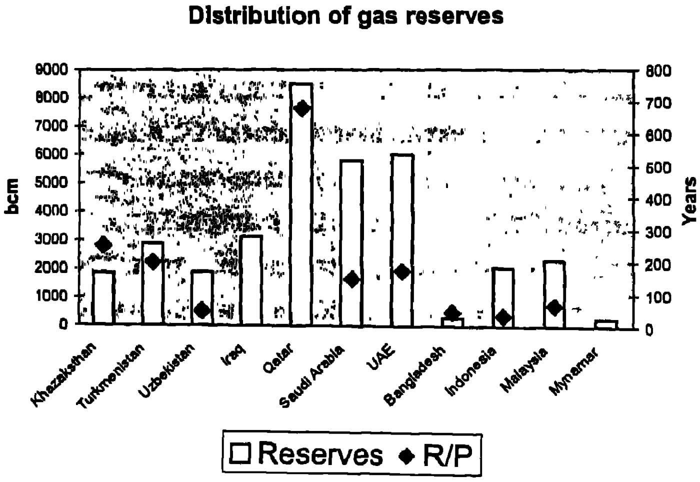
Import options

There are two options for importing gas into the country—piped gas and LNG. The options have their merits and demerits as shown below.

Table 14 Pipeline vs LNG

Critical factors	Pipeline	LNG
Technology	Established (Few issues in deep water technology to be resolved)	Established
Investment	Large investments upfront	Large investments Phased
Flexibility	Low	Relatively High
Delivered price of gas	Lower (for smaller sized pipelines upto a distance of about 1600 km; for larger pipelines upto 5000 km)	Higher
Contractual framework	Complex especially if pipeline transiting through other countries	Complex
Geo-politics	Strong influence	Minor issue

The distribution of gas reserves in countries around the Indian sub-continent are shown below:



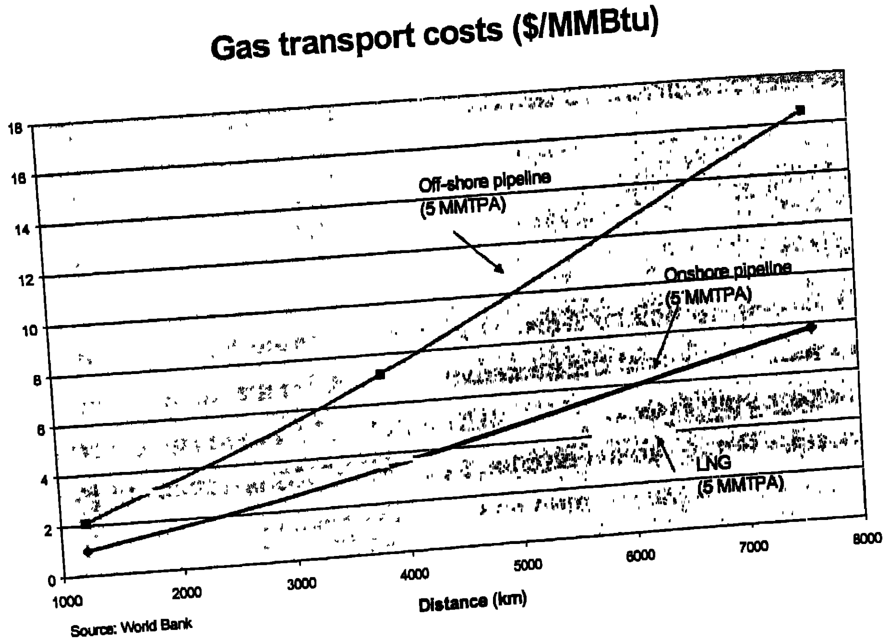
According to estimates, off-shore pipelines are cheaper than LNG for distances less than 2000 km but beyond that the reverse holds true. The comparison with on-shore pipelines, however, reveals that LNG is relatively more expensive upto distances of 4000-5000 km. The costs shown below are illustrative, and the actual costs will depend critically on project characteristics. In fact, with improvements in technology, the relative costs of pipelines and LNG may change significantly.

Piped gas

On account of the growing demand for gas and the limitations of indigenous resources, a number of gas import projects have been pursued. These include:

Oman to India via a deep water pipeline

It was envisaged that two deep-sea pipelines would bring 56.6 MMCMD of gas from Oman to Gujarat. Half the gas could be used in the HBJ command area and the other half taken to south India. The Oman Oil Company (OOC), which was to lay the offshore pipeline, had indicated that an investment of US$5 billion would be required. The OOC is no longer interested in the project, as the feasibility of the deep-sea pipeline could not be proved.



Gas transport costs ($/MMBtu)

Source: World Bank

Iran to India via Pakistan

A feasibility study for this project was awarded to PLE of Germany. However, the study could not get off the ground as the government of Pakistan did not give permission for the pipeline route survey.

Pakistan has favoured a pipeline route passing overland through its territory allowing it to tap some gas also. India agreed to examine this option along with the subsea route. However, no progress has been made either way.

Turkmenistan to India via Afghanistan and Pakistan

This project was at one time being pushed by UNOCAL who were pursuing an alignment through Afghanistan and Pakistan. There are obvious political and security problems associated with the project and an early breakthrough is not expected. UNOCAL has since withdrawn from the project.

Myanmar to India via Bangladesh

The bulk of the discovered gas off the Myanmar coast has been committed for supply to Thailand. However, exploration for more gas continues and in case more gas becomes available, it may be feasible to transport it to India through an offshore pipeline in combination with gas from Bangladesh. A pre-feasibility study of these options is under way.

Bangladesh to India

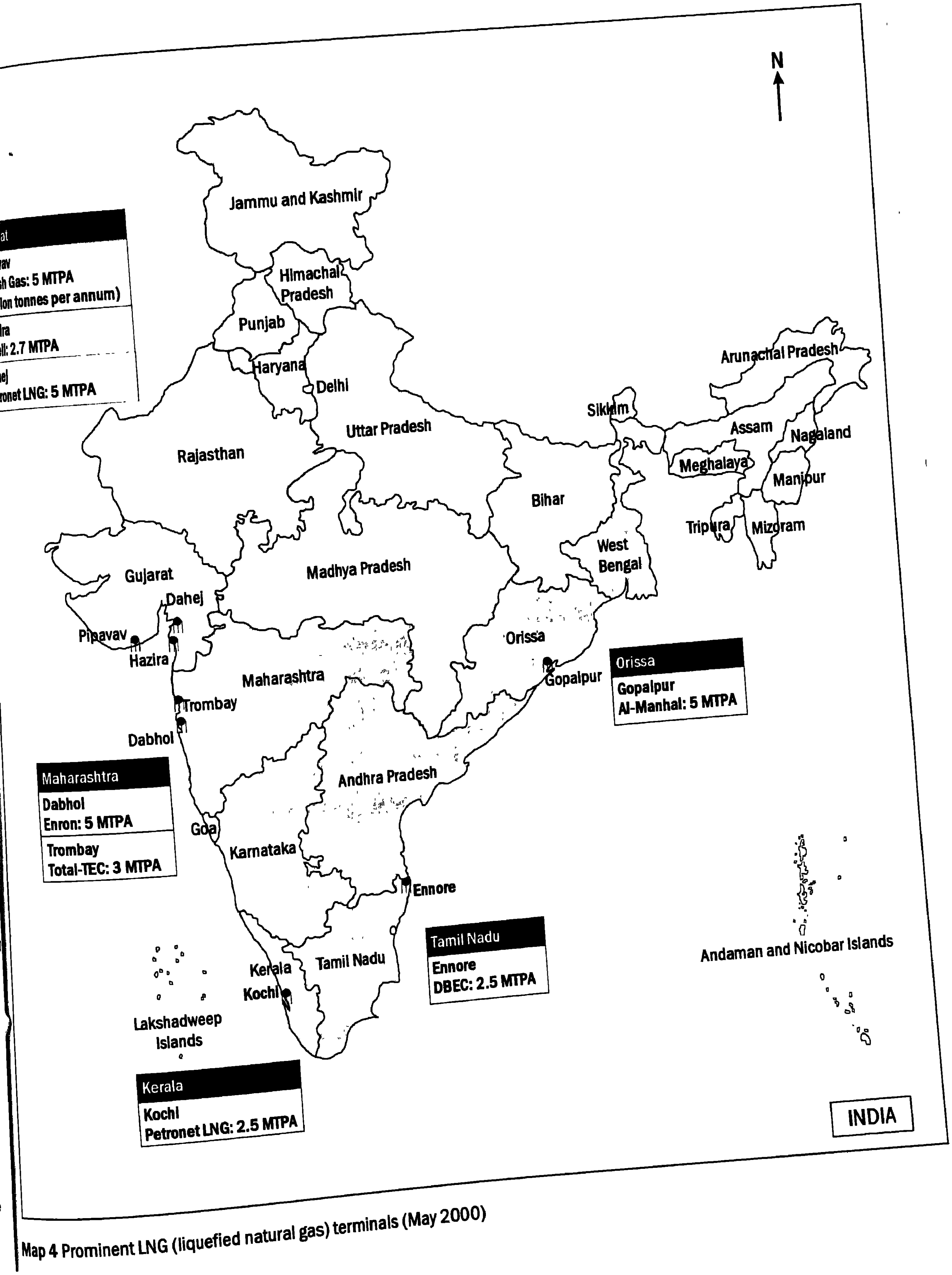
Current estimates put the proven reserves of gas in Bangladesh at around 310 MMCM (11 tcf). The potential reserves are 3-4 times more. This is perceived as an attractive source for piped gas into India with significant mutual benefits for both countries. However, gas can be exported from Bangladesh only after the internal requirements in the country have been met.

LNG option

In view of the problems faced by the pipeline projects, LNG import options have been pursued to meet the immediate needs for imported gas. Four large oil and gas sector units (ONGC, GAIL, IOC, and BPCL) have formed Petronet LNG to import LNG into India. Petronet is planning LNG terminals at Dahej in Gujarat and Cochin in Kerala. A number of private projects for importing LNG have also been cleared by the FIPB. The locations of the proposed LNG terminals are shown in Map 4. The table below shows the status of some of these LNG initiatives.

Table 15 Status of LNG projects

Name of the company	Name of foreign collaboration	Location of proposed terminal	Capacity of termination million tonnes per annum	Gas supply to	FIPB clearance	CCFI clearance
Enron International Inc.	Enron International Inc.	Dabhol (Maharashtra)	Initial 2 MMTPA expand to 5 MMTPA and further to 11 MMTPA	Maharashtra and other states	Yes, on 12.6.97 for holding company. 23.8.97 Project Clearance with Investment from its affiliates	Yes, 19.9.97
(British Gas) BG Plc.	(British Gas) BG Plc.	Pipavav (Gujarat)	Initial 2.5 MMTPA expand to 5 MMTPA	Gujarat	Yes, 23.8.97	Yes, 17.9.9
Ispat Group of Industries	Ispat Energy Ltd.	Kakinada (A.P)	Initial 2.5 MMTPA expansion unspecified	A.P.	Yes, 18.10.97	Yes
Reliance Industries Ltd.	GDR/ADR/Private placement	Jamnagar and Hazira (Gujarat)	5MMTPA at each terminal	Gujarat and other states	Yes, 29.11.97	Yes
Royal Dutch Shell Group of companies	Royal Dutch Shell Group of companies	Hazira (Gujarat)	2.7 MMTPA initial. Expansion unspecified	Essar Power Ltd. And Essar Steel Ltd.	29.11.97	Yes
Gas de France (GDF)	GDF International Paris	Dahej, Gujarat	5 MMTPA	Gujarat and others states	27.6.98	Yet to be given
CMS	CMS	Kakinada A.P.	-	A.P.	Yes	



Map 4 Prominent LNG (liquefied natural gas) terminals (May 2000)

Name of the company	Name of foreign collaboration	Location of proposed terminal	Capacity of termination million tonnes per annum	Gas supply to	FIPB clearance	CCFI clearance	FDI
Energy/UNOCAL /GVKTractabel	Energy/UNOCAL						
Total/TEC	TOTAL	Trombay, Maharashtra	2.5 MMTPA	Maharashtra	Yes		
TIDCO		Ennore	5	Tamil Nadu			

LNG supplied from the Middle East could be the best source of imported gas for the western coast as well as the eastern coast. The enormous gas reserves in Qatar are already being used by LNG projects and Qatar has the reserve base to supply the volumes which will be required in India. Iran has shown interest in supplying gas through sub-sea pipeline as well as in the form of LNG. Oman is the closest LNG producer to India although there is some doubt as to whether Oman has sufficient gas reserves available to support further LNG projects. Iran could exploit offshore gas fields for LNG; the economics would be the same as those of Qatar. LNG from Malaysia would be as competitive on the east coast. Australia could also emerge as a source to south eastern states such as Andhra Pradesh. However, due consideration is being given to the implications of huge imports of LNG in terms of investments involved

The following estimates for the cost of power provides a comparison of the alternative fuels.

Table 16 Cost of generation: fuel component (Paise/kWh)

	At port location, cif	At burner tip
Imported coal	69.52	94.42
LNG	112.17	131.45
Naphtha	155.70	239.59

Similarly, estimates for the fertiliser sector show that imported LNG will be the appropriate feedstock for future expansion in the fertilizer sector.

Table 18 LNG for urea production

Feedstock	Investment (rs crores)	Energy cons (Gcal/tonne of urea)	Feedstock price (rs/tonne of urea)
Indigenous gas	1425	5.07	2161
LNG	1425	5.07	3385
Naphtha	1474	5.10	4097
Fuel oil	1976	6.57	3921

Clearly LNG will need to be supplied to India at an affordable price, and the underlying economics indicate LNG can be supplied at affordable prices in India. A critical issue will be the pricing mechanism utilized for supply to India.

Technological development and cost reduction

There has been a continuous increase in size of both the liquefaction facilities and LNG ships over the past 30 years. As a result, unit cost of LNG has declined, but this has been accomplished by rising investment in larger LNG project facilities and dependence on expanding markets to absorb the greater capacities of a single train of LNG production. The capital cost estimates for LNG projects are now being challenged in a variety of ways as industry-wide efforts aim at capital cost reductions. Technical developments aim at capital cost reduction at all functions in the LNG chain:

- Larger LNG train side to achieve greater scale economy;
- Higher thermal efficiency in the liquefaction process;
- Gas treatment process tailored to specific feed-gas composition;
- Larger compressors and gas turbine drivers for the refrigerant process;
- Increased plant efficiency and availability;
- Larger LNG storage tanks, and;
- Larger LNG ships.

Cost cutting is another measure that could make LNG more competitive in world fuel markets and will be an imperative for competing projects to penetrate into new markets. Cost reductions may take place in all segments of the LNG value chain from upstream gas production through liquefaction and transport to regasification. The liquefaction plant accounts for about 40% of the capital expenditure in an LNG chain with transport representing around 30%. These are the most important areas for cost reduction. Improvements are being made in the liquefaction process and average train sizes are increasing. Competition amongst construction companies is also forcing costs down. In shipping, the largest LNG tankers offered by shipbuilders have now increased from 137,000 to 165,000 cubic meter capacities, and this figure is expected to increase further in future. Decreasing costs could make LNG more competitive.

As of today, there are only 9 Producers of LNG with an installed capacity of about 80 MMTPA (Working Capacity would be around 100 MMTPA). However, there is a number of expansion projects and new proposals for LNG supply. The capacities being discussed are as below:

	Nameplate capacity
Existing LNG project	79.7
Planned LNG projects	17.3
Probable LNG projects	31.0

Natural gas pricing

History of gas pricing

The price of natural gas has been fixed by the Government since 1987. In 1987, the price was $ 0.86/MMBtu ($1= Rs 46) for gas at landfall points and a flat $ 1.38/MMBtu for gas along the HBJ line. By 1989 it was decided that this system was no longer appropriate and the Kelkar committee was established to look into gas pricing.

In responding to the Kelkar committee recommendations in 1992, the Government introduced a sale price of $ 0.95/MMBtu at landfall to be increased each year by $ 0.06 until it reached $1.13/MMBtu. Transportation charges along the HBJ were set at $ 0.52/MMBtu. The producer price payable to ONGC was kept fixed at $0.92/MMBtu and the difference between the consumer price and the producer price was credited to the Gas Pool Account – an account set up to compensate ONGC and OIL for the concessional price of gas in the North East.

In 1996 the Sankar Committee was established to review the above rates, with some consideration given to the impending need for gas imports and the effects of import parity pricing. The committee decided that import parity pricing would be too steep a transition and recommended producer prices of $ 1.20/MMBtu for ONGC and $ 1.26/MMBtu for OIL. Transportation charges were set at $ 0.71/MMBtu for transportation along the HBJ line. The consumer prices were set at the sum of producer and transportation rates with an additional $ 0.16/MMBtu to be contributed to the Gas Pool Account.

Having considered these recommendations, in October 1997 the government instituted a new series of gas prices, valid through to March 31, 2000. The consumer price of gas at landfall points were linked to the price of a basket of fuel oils as shown in the table below:

Table 19 Natural gas pricing against a basket of fuel oils

	Percentage of LSHS/FO price	
Year	General price (%)	Concessional price for the NE states (%)
1997-98	55	35
1998-99	65	40
1999-2000	75	45

The price is expected to reach 100% parity by 2002. The price is determined and notified by GAIL with the approval for the Ministry for every quarter depending upon the average price of the following basket of fuel oils (with equal weights to each type) based on the figures obtained from Platt's Oilgram for the previous quarter.

- Cargoes FOB, Med Basis, Italy (1% Sulphur)
- Cargoes CIF NEW Basis, ARA (1% Sulphur)
- Singapore, FOB, HSFO 180 cst (3.9% Sulphur)
- Arabian Gulf, FOB, HSFO 180 cst (3.9% Sulphur)

The price varies between the floor of \$ 1.40/MMBtu and the ceiling of \$ 1.90/MMBtu and the concessional price for the North-Eastern States has a floor of \$ 0.80/MMBtu and the ceiling of \$ 1.10/MMBtu. A discount of \$ 0.20/MMBtu is available on a case to case basis to the new units in the North-Eastern States set up during 1997-2002 for a period of five years. The consumer price of gas as above is linked to a calorific value of 10000 kcal/m^3. The consumer price is being reviewed with a view to introducing 100% fuel oil parity prices by 2002.

ONGC/OIL/GAIL and joint venture operations are permitted to sell gas from marginal isolated fields to be developed in future, at market driven prices.

The transportation charge along the HBJ pipeline has increased since 1997 by 1% for every 10% increase in the consumer price index. This increase is paid to GAIL out of the Gas Pool Account. The transportation charge has been linked to the calorific value of 8500 Kcal/m^3 until such time as it could be denominated in terms of calories. Out of the consumer prices collected by GAIL, GAIL retains the amount required to pay for the higher cost of gas purchased from the joint venture companies who are paid full fuel oil parity prices.

An amount of \$ 59 million per year is also deducted by GAIL from the consumer revenues collected and credited to the Gas Pool Account to compensate OIL for concessional gas price in the North-East and to provide a marketing margin to GAIL. The pool is also used to compensate GAIL/OIL for increases in the operating cost on account of inflation and for utilisation on R&D for exploration and exploitation of small fields. Any balance amount left in the Gas Pool Account after taking care of the above requirements would be transferred to the central exchequer. For the purpose of compensating OIL for concessional gas price in the North-East, the producer price of OIL is \$ 1.26/MMBtu which is increased by 1% for every 10% change in the consumer price index. The producer price of gas payable to ONGC/OIL until 30.9.1997 was $ 1.10/MMBtu.

The above prices are applicable to gas sold by ONGC or OIL to GAIL and to sales by GAIL to consumers. Sales by private field operators are linked to fuel oil prices. The prices applicable at different interfaces are as shown below.

Gas sales by ONGC/OIL to GAIL

As detailed above.

Gas sales by private upstream companies

To GAIL

These are negotiated between the government and the private operators and included in the production sharing contracts. So far these prices have been full fuel oil parity prices but the fuel oils basket could differ from one case to another.

Direct to end-users

These are freely negotiated and are mostly linked to prices of alternative fuels. Transportation charges are also negotiated.

Gas sales by GAIL to end-users

As detailed above. The transportation charge on the HBJ pipeline provides GAIL a 12% post-tax return on net worth. The transportation charges on other pipelines is fixed by GAIL on the same principle.

Gas sales by GAIL to distribution companies

The distribution companies pay the same price to GAIL as any other customer.

Gas sales by distribution companies to end-users

These are negotiated prices linked to alternative fuels.

Taxes and duties

In addition to the price as fixed above, royalty, taxes, duties and other statutory levies on the production and sale of natural gas is payable by the consumer. The royalty on gas as fixed under the Oilfields Development Act is 10% of the wellhead price. For gas sold by ONGC, this is now $0.18/mmbtu, one-tenth of the ceiling price of $1.80/mmbtu. For privately operated fields, the royalty is fixed on the negotiated wellhead prices. There is no cess on natural gas (unlike crude oil) although a cess could be levied under the law. There is no excise duty as natural gas is a mineral. A sales tax is leviable at state rates if the sale is within the state or at the central rate of 4% for inter-state sales. The state sales tax rates vary from one state to another, ranging from zero to 22%. The high rates of sales tax do not disadvantage gas against other fuels as similar taxes apply to other fuels also.

A typical price build up for gas produced in a state and sold within the state would be as below:

	$ / MMbtu
Gas price	1.80
Royalty	0.18
Transportation charge	0.43
Sales tax (20%)	0.48
Total	**2.89**

It is to be noted that GAIL does not make a margin on merchant sales; it is allowed a return only on its investment in the pipeline.

Gas industry regulations and outlook

The natural gas industry in India is in transition as it attempts to move from a highly centralized, government-controlled business to one that relies increasingly upon reduced regulation and a more market-responsive pricing climate to encourage foreign and private sector investment. To promote private sector investment and more widespread use of natural gas in its economy, the Government is evaluating alternatives to its existing gas transportation regulatory framework and organisational structure. In order to examine the options for a regulatory framework for the gas industry, the government commissioned a study by the National Economic Research Associates of UK. This report is under consideration of the government. A summary of the recommendations is given below.

- Exclusivity to develop new transmission lines, and extensions and additions to new lines, should not be granted to GAIL or any other entity, in order that there can be some element of competition in the provision of new facilities. However, the regulatory framework should be established in such a way as to ensure that the orderly development of the industry can be ensured.
- Gas transportation should be provided on the basis of "unbundled" service, that is separate provision of transportation and gas supply services.

- The framework of regulation should be established such that transmission services be provided on the basis of contract carriage. This ensures efficiency in that capacity is constructed where there are users prepared to pay for it. Individual pipeline operators (transmitters) have only limited responsibility for system development.
- The regulatory body should be empowered to ensure that effective transportation contracts are put in place for all existing and new users of the existing facilities.
- Regulatory powers be provided with regard to the contract terms on which new transmission facilities are developed, this being a condition for regulatory approval of new transmission pipelines.
- Regulatory powers be provided with regard to the interconnection of new and existing lines.

Distribution systems should be regarded as separately regulated entities, and subject to distinct regulatory provisions:

- The regulation should provide for exclusive franchises for distribution, this being the only sensible option in the Indian context;
- Cross-ownership between distribution, transmission, and bulk supply be permitted, but that there are regulatory provisions concerned with the transparent separation of accounts between the different businesses.
- As regards bulk gas supply, transmitters of gas should also be permitted to sell gas subject to appropriate regulatory safeguards. In particular, this would mean full and transparent separation of accounts for the transmission and trading activities.
- In the long term there is no need to regulate the price of bulk gas supplies. Interim measures, such as regulated bulk supply contracts for existing supplies will be necessary to ease the transition to full price liberalisation.

The government has so far controlled gas production and marketing by virtue of being the owner of ONGC and GAIL. With the entry of private parties, government would need to acquire statutory powers. Ever since the submission of the NERA report, there has been an expectation of a Gas Act installing an independent regulator. Such regulators are already in place for the electricity and the telecom sectors. It seems however that the government is not yet prepared to have an independent regulator in place and that regulation by government would continue for sometime. The existing set up is dominated by public sector undertakings who are happy with direct regulation by the government and there is no pressure from any quarter for an early passing of the Act. The only possible pressure could come from the potential LNG suppliers who may need to have a transparent system in place in order to secure finance for their projects. However, no private sector LNG project has reached that stage yet.

In the absence of legislation, there are no specific restrictions covering the role of the private sector in the building of gas pipelines or LNG terminals. However, in practice, the private entrepreneur trying to build such infrastructure may face a number of constraints. A foreign company requires permission to invest from the Foreign Investment Promotion Board. For a LNG terminal, permission must be secured from the port authority or the state maritime board. The design of the regasification terminal has to be approved by the chief controller of explosives from the point of safety. The rights of way for pipelines must be secured under the relevant Act administered by the petroleum ministry. Clearance from the environmental angle must be sought at both central and state levels. A number of other permits must then be obtained from the state department of industry and other authorities.

These difficulties may look formidable when listed out but judging from the number of proposals being enthusiastically pursued, it appears that the government's policy of supporting these initiatives is working.

Gas allocations to consumers

The government has all along been regulating all aspects of the gas sector. Gas prices have been fixed by the government since 1987. The government also makes gas allocations to individual consumers. The regime of allocation was based on the premise that gas was in short supply and that the government was the best judge of how to use the gas. Following the recommendations of the Varadharajan committee (1987), these allocations were based on the imputed values of gas use in the various sectors, subject to preference for the power and the fertiliser sectors. The sectoral pattern of gas use would, however, not be widely different if allocations were left to the market. The first departure from this system of allocation was made in the cases of private producers of gas under production sharing contracts. These developers were free to choose their customers and sell gas to them at negotiated prices.

It may be noted that gas allocations were made by the government as shareholders in the public sector gas producers and marketers. Since this was not done under a statutory power, private sector gas producers or importers of LNG are outside the purview of these allocation orders. As noted earlier, the

NELP places the NOCs on a level playing field with private operators. This means that the NOCs would be free to market gas produced from fields acquired under the NELP just as private operators are. Allocations may however continue for gas produced from fields settled with NOCs prior to NELP.

Energy sector policies

We discuss below the policy initiatives in the related sectors of petroleum products, coal, power and fertilisers. As seen above, the private sector has been allowed into exploration and production of gas. Transportation and distribution of gas is still very much in the public sector but policy changes to facilitate the entry of the private sector are under consideration. Similar changes have affected the related sectors also to varying extents. The progress of reforms in these sectors would affect the way the natural gas/LNG industry develops.

The policy reforms were started in 1990-91. Since then there have been several changes in the government. This has no doubt affected the pace of reforms but there seems to be a broad consensus on the need for such reforms among the national level political parties.

The oil sector

At the time of independence, the petroleum industry in India was run by multinational companies, Burmah Shell, Mobil and Caltex being the most active. The ONGC and the Indian Oil Corporation were formed in the late fifties. In the seventies, the assets of the MNCs were nationalised. By the time the economic reforms were launched in the nineties, the industry was dominated by public sector companies engaged in exploration, refining, marketing and distribution.

The upstream sector was the first to be opened up to the private sector. As mentioned earlier, exploration bidding rounds picked up momentum in the nineties. Next, the private sector was allowed into refining. This has proved to be the most successful initiative so far resulting in 27 MMTPA of additional capacity put up by Reliance at Jamnagar and other proposals in the pipeline. Opening up of the lucrative marketing sector has been scheduled for April 2002. Entry would be subject to the investment of Rs 20 billion in refining or the production of 3 MMTPA of oil (these criteria are expected to be rationalised).

Opening up the petroleum industry called for major changes in regulation. These regulations were built around the Administered Pricing Mechanism (APM) introduced in 1976. The APM works as follows:

- The cost of crude included in the selling price is computed at weighted average price of indigenous and imported crude oil.

- Standards are laid down for each refinery in respect of throughput level, product pattern, fuel and loss, operating cost and capital employed.
- The total cost of production and the refiners' profit are estimated based on the above standards. The refineries are allowed a 12% post-tax return on net worth and actual interest cost on the borrowings included in the capital employed (Net Fixed Assets plus Normative Working Capital). A set of indices is used for allocating the costs over products. These indices have been developed taking into account mainly the distributional and allocative efficiency.
- Ex-refinery price, which is the price at which products are sold to marketing companies, is uniform at all the refineries. The ex-refinery price is based on the weighted average cost of products of all refineries.
- The marketing costs and profits (referred to as marketing margins) are also estimated taking into account the norms fixed for marketing operations. As in the case of refineries, the marketing companies are allowed an after tax return of 12% on net worth and reimbursement of borrowing cost. The marketing margins are averaged out to compute industry margins for inclusion in the selling price.
- The selling price of products to the consumer includes, in addition to industry average costs and profits, notional railway freight (from the most economic source irrespective of the actual supply point), retailing cost wherever applicable, various surcharges and governmental levies.
- Irrespective of the company marketing the product and the location from which the product is actually sourced, prices of products at a location are maintained at an uniform level.
- Products like SKO, LPG (Domestic), Naphtha, LSHS and FO for fertiliser units, and Bitumen are subsidised. The cost of the subsidy is borne by products like MS, ATF (Domestic Airlines), LPG (Bulk), Naphtha, FO, LSHS (for use other than fertilisers).
- In order to maintain this system, OCC operates a number of pool accounts. Companies either pay to or recover from these accounts, in order to retain their margins. Rewards and penalties are in-built in the system.

This mechanism has served the following objectives:

- To ensure availability of certain products at subsidized rates to the economically weaker sections of the society and for priority sectors like fertilizers. This is achieved through a system of cross subsidization of products,

- To ensure stable prices so that the domestic market is insulated from the volatility of prices in the international market,
- To regulate returns to the oil companies at reasonable levels consistent with efficiency of operations, to generate sufficient resources for encouraging growth of infrastructure facilities,
- To minimize the cross haulage of products by making available products at a uniform price ex-all refineries, and
- To achieve social objectives such as demand management.

In spite of these features, the system proved unworkable for several reasons. The cost-plus method of pricing did not provide incentives for efficiency. The government was reluctant to increase product prices in step with rising costs and the dues to the oil companies mounted so much as to affect their financial health. The government accordingly favoured the introduction of market prices. An expert group called the R-Group was formed to examine ways of bringing in the change. The government accepted the recommendations of the group and announced a phased reform program starting April 1, 1998. The important features of the program were:

- Fixed time frame for implementation (1998-2002)
- International price for domestic crude oil
- Retention pricing for refineries abolished
- Ex-refinery prices of controlled products to be fixed by OCC
- Adjusted import parity for existing refineries
- Tariff adjusted import parity for new refineries (set up after 1.4.98)
- Decontrolled products – refineries free to set own prices i.e. naphtha, fuel oil etc.
- Rationalization of customs duty on crude & products to provide tariff protection to refineries
- Marketing rights of transportation fuels to new players subject to conditionalities
- Phasing out of subsidies. Subsidies beyond 2002 to be funded from general budget
- Regulatory body to be established.

Off and on there have been press reports on the scheduled price decontrol getting delayed or being advanced. As of today it seems the timetable would be adhered to.

Coal

Coal is the most abundant fossil fuel in India. It accounts for 56% of the country's primary energy supply and about the same percentage of the power generation capacity. The country's industrial heritage was built upon indigenous coal. The coal available in India is primarily low grade non-coking coal. This coal is characterised by a high ash content (upwards of 40%), low calorific content and very low sulphur content.

The coal industry in India was largely in the hands of the private sector until the end of 1971. There was a large number of operators of varying sizes. National Coal Development Corporation (NCDC) and Singareni Coal Company (SCCL) were setup in the public sector in the fifties. SCCL was formed in 1950 as a joint venture with the state of Andhra Pradesh to mine coal in southern India. NCDC was founded in 1956 primarily to locate and mine coal from outlying coalfields in central and western India. NCDC took the lead in exploiting shallow deposits through mechanised open cast mining.

The coal industry was nationalised in two stages - coking coal mines were taken over in October 1971 and other coal mines in January 1973. Subsequently, the industry was reorganised with Coal India as the holding company and seven coal producing subsidiaries, operating mines in different regions.

The industry was nationalised, apart from other considerations, with a view to ensure that the production of coal should be properly planned to meet the increasing requirements in the industrial development of the country. It was expected that nationalisation of the coal industry would also ensure fair and equitable distribution of coal to meet the essential needs of users, both in the core and non-core sectors. To ensure sustained and planned development of all facets of the coal industry, a massive investment to the tune of about Rs. 180 billion has been made in opening up of new mines, re-organisation of existing mines and development of associated infrastructure.

Coal production has registered an annual growth rate of about 4.8 % since nationalisation, increasing from a level of 73 MMT in 1970/71 to 300 MMT in 1999/2000. In the post-nationalisation period, the major thrust was on the development of new outlying coalfields like Rajmahal, North Karanpura (Bihar), Singrauli, Korba (MP), Ib Valley and Talcher (Orissa). These coalfields contributed 43% of the total coal production in 1994/95. Their contribution is projected to be 60 % by the year 2010/11. Consequent upon the development of new coalfields in outlying areas, a large number of pithead super thermal power stations have come up. This has helped in reducing the load on railways as most of these pithead power stations transport their coal by captive modes such as merry-go-round and cross country belt systems.

Till the end of the Seventh Five-year Plan (1990) the coal sector depended fully on the budgetary support provided by the government for new developments including exploration. From the Eighth Plan onwards, the government has phased out this support. Due to this reason, investments in new projects has been low in the last few years. This is likely to increase the gap between production and demand in the future.

Since nationalisation, coal prices have been regulated and revised several times on the suggestions of Committees and Working Groups set up by the Government.

In the pre-nationalisation period, coal prices remained fairly low. The prices increased at a rate of 3.5 % during the 1950s and 5.6 % during the 1960s. The post-nationalisation period witnessed a sharp rise in prices, registering an annual rate of increase of 12.8 percent during 1970/80 and 9.7 percent during 1980/95.

In general, all the committees advocated that the pithead price of coal should be related to the industry-wide average cost of production with suitable allowance made for cost increases. The Bureau of Industrial Costs and Prices (BICP) has been working out normative costs based on normative rather than actual levels of efficiency and had been recommending a weighted average price on the basis of the estimates from different categories of mines. However, the coal industry has not been able to achieve these normative levels of efficiency or the projected mix of production of different grades of coal. The industry was therefore not fully compensated for their costs and the financial health of the coal companies deteriorated over time.

In 1996, the government deregulated the prices of A, B & C grades of non-coking coal and all grades of coking coal. In February 1997, the government decided to deregulate the prices of 'D' grade non-coking coal, hard coke and soft coke. Finally, the prices of E, F & G grades of coal were decontrolled on 1st January 2000.

Since the capacity in eastern sector is larger than the demand, coal moves over long distances to the north and west. The freight rate is more than 50% of the delivered cost of coal at 1000 km. With coal prices decontrolled, consumers should be able to strike deals with nearby fields and the movement of coal is expected to reduce.

The government protects the domestic industry with a customs duty. In the case of non coking coal, the present rate of custom duty is 15 % with a surcharge depending on the ash content. The import of coal is however increasing and around 7.5 million tonnes of non-coking coal were imported last year.

In a major policy initiative, Captive Coal Mining has been allowed to both private sector and public sector companies including the state level power utilities for generation of power, production of iron and steel, cement and for washing of coal. Foreign investment in Indian companies taking up coal mining activity for captive consumption for approved end-uses has been allowed. The extent of equity participation is decided on a case to case basis. 82 mining blocks have been identified for captive mining with an estimated coal reserve of 20 billion tons and annual production potential of 150 million tons. Of these, 23 blocks have already been allotted to power producers and 4 to the steel industry. Captive mining is yet to really take off. Lack of facilities such as power and railway lines near the allotted blocks as well as the difficulties in the power sector have been the important factors.

Private investment is also being invited in clean coal technologies like Integrated Gassification Combined Cycle (IGCC), Pressurised Fluidised Bed Combustion (PFBC), Coal Beneficiation and Slurry Combustion, In-situ Coal Gassification.However, the results have not been very encouraging till date. For coal sector reforms to take off, it may be necessary to appoint an independent regulatory body for this sector. The government has recently completed studies in this regard. The report is under consideration in the government.

Electricity

Like the petroleum industry, the power sector has been characterised by cross-subsidies. In the oil industry these cross-subsidies are between products; in the power sector these are between different kinds of consumers. Supplies to the agricultural and residential sectors are subsidised by overcharging industrial consumers. As the limits of cross-subsidy were reached, net subsidies from the government were required. These were mostly inadequate and often delayed. The result was that the electricity boards in the states suffered losses and were in no position to meet the rising demand for power. There was a clear need to rope in the private sector in power generation, transmission and distribution and the institutional set up had to be changed to make this possible. An important landmark in this process was the meeting between the Prime Minister and the Chief Ministers of the states in December 1996. The main features of the Minimum National Action Plan adopted in the meeting are listed below.

- Central Government will set up a Central Electricity Regulatory Commission (CERC).
- Each State and Union Territory will set up a State Electricity Regulatory Commission (SERC).
- Central Government will issue transparent guidelines and delegate more powers for environmental clearance to the state agencies.
- States to allow maximum autonomy to the SEBs and they will be restructured and run on professional lines.
- Rationalisation of retail tariffs to be carried out over time. No sector to pay less than 50% of the cost of supply. Agricultural tariff was to be at least Rs. 0.50 per kWh and to be brought to 50% of the average cost of supply in not more than three years.
- The supply to the agricultural consumers is to be metered.
- Steps to be initiated by the states to introduce participation of private sector in electricity distribution.
- SEBs to improve their professional standards and project management practices.
- Central Government to finalise the linkages of allocation of liquid fuels in consultation with the State Governments.
- States to evolve transparent policies for purchasing and wheeling of power for captive and cogeneration plants.
- Steps to be initiated to improve the physical performance like PLF of the plants, metering etc.
- High priority to be accorded to the hydro projects and the Central Government to evolve a policy framework for the same.

The important initiatives taken in accordance of the above decisions are discussed below.

Central Electricity Regulatory Commission

The Electricity Regulatory Commission Act, 1998 came into force in July 1998. This Act provides for the establishment of the Central Electricity Regulatory Commission to regulate the tariff of the generating companies owned by the central government, to regulate the tariff of other generating companies selling electricity to two or more states and to regulate inter-state transmission of electricity. The Act also provides for the establishment of state level regulatory commissions.

The Central Electricity Regulatory Commission was constituted as a statutory body in July 1998 with a Chairperson and three members. The functions of the CERC include the following:

- To regulate the tariff of generating companies owned or controlled by the Central Government.
- To regulate the tariff of generating companies, other than those owned or controlled by the Central Government specified in clause (1), if such generating companies enter into or otherwise have a composite scheme for generation and sale of electricity in more than one State;
- To regulate the inter-State transmission of energy including tariff of the transmission utilities;
- To promote competition, efficiency and economy in the activities of the electricity industry;
- To aid and advise the Central Government in the formulation of tariff policy which shall be:
- Fair to the consumers;
- Facilitate mobilisation of adequate resources for the power sector;
- To associate with the environmental regulatory agencies to develop appropriate policies and procedures for environmental regulation of the power sector;
- To frame guidelines in matters relating to electricity tariff;
- To arbitrate or adjudicate upon disputes involving generating companies or transmission utilities in regard to matters connected with clause (a) to (c) above;
- To aid and advise the Central Government on any other matter referred to the Central Commission by that Government.

The Transmission Bill

The Transmission Bill facilitating the entry of private sector in the transmission business was passed by the parliament recently. The bill is aimed only at facilitating the private investment. The Government will continue to retain control over power transmission through central grids or SEBs. The bill will allow private firms to invest in facilities for transmission and to operate and maintain these facilities.

Mega power projects policy

In view of the slippages in setting up additional generation capacity in the Ninth Plan, the government has announced a policy package for mega power projects to be developed in the country. To qualify for incentives under this scheme, a project has to satisfy the following three conditions:

- The capacity should be more than 1000 MW in case of thermal power projects and 500 MW in case of hydroelectric power projects.
- The project should sell power to more than one state.
- The tariff should be approved for Central Electricity Regulatory Commission.

The policy will be applicable to government-owned as well as privately owned projects. The government expects to add approximately 25,000 MW of capacity through such projects, of which the private sector is expected to contribute about 40%.

The incentives include a complete waiver of the customs duty on import of equipment, which is currently more than 20 percent. It also provides a 15% price preference and deemed export benefit for domestic bidders.

Further, it is proposed that the recently formed Power Trading Corporation (PTC), with equity participation of NTPC, NHPC, PGCIL and financial institutions such as PFC will act as an intermediary between the private developers of mega projects and the State Electricity Boards. This arrangement will work as a de facto counter-guarantee. However, the Central Government has imposed conditions which have to be satisfied before PTC can sell power to a State Electricity Board. The concerned State must have established a State Electricity Regulatory Commission and should have involved the private sector in the electricity distribution business.

The fertilizer sector

The increase in fertilizer consumption has contributed significantly to a more or less sustained improvement in the production of foodgrains in the country which has risen from a modest level of 52 million tonnes in 1951-52 to 202.54 million tonnes in 1998-99.

Although the average per hectare consumption of fertilizer nutrients has increased from less than 1 kg. in 1952-52 to about 90.04 kg. in 1998-99, even this level of fertilizer use is low with reference to the objective of accelerating growth in the agriculture sector as well as the consumption levels prevailing in other countries including some of the developing countries in Asia. Moreover, the consumption of chemical fertilizers in the country is unevenly distributed, being much higher in regions with assured irrigation.

The Indian fertilizer industry has been supplying a substantial portion of the growing demand of fertilizers. It had a very humble beginning in 1906, when the first manufacturing unit was set up in Ranipet near Chennai with a production capacity of 6000 TPA of Single Superphosphate. The Fertilizer and Chemicals Travancore Ltd. (FACT) at Cochin in Kerala and the Fertilizer Corporation on India Ltd. at Sindri in Bihar were the first large sized fertilizer plants to be set up in the forties and fifties with a view to establishing a base for industrialization and achieving self-sufficiency in foodgrains. The Green Revolution in the late sixties gave an impetus to the growth of the fertilizer industry in India. The eighties witnessed a significant addition to the fertilizer production capacity.

The installed capacity as on 29.2.2000 has reached a level of 11.71 million MT of nitrogen (inclusive of an installed capacity of 20.67 million MT of urea) and 3.65 million MT of phosphate nutrients, making India the third largest fertilizer producer in the world. The rapid build-up of fertilizer production capacity in the country has been achieved as a result of a favourable policy environment and substantial investments made over the years in the public, co-operative and private sectors. Today, there are 64 large sized fertilizer plants in the country, manufacturing a wide range of nitrogenous, phosphatic and complex fertilizers.

Of the three main nutrients required for various crops – nitrogen, phosphate and potash, indigenous raw materials are available mainly for nitrogen. The Government's policy has aimed at achieving the maximum possible degree of self-sufficiency in the production of nitrogenous fertilizers based on utilization of indigenous feedstock. As of now, the country is self-sufficient to the extent of about 92.1% in the case of nitrogen. Prior to 1980, nitrogenous fertilizer plants were based mainly on naphtha as feedstock. A number of fuel oil based ammonia-urea plants were also set up during 1978 to 1982. In 1980, two coal-based plants were set up for the first time in the country at Talcher (Orissa) and Ramagundam (Andhra Pradesh). With associated and free gas becoming available from offshore Bombay High and South Bassein basins, a number of gas based ammonia-urea plants have been set up since 1985. In view of the limitations on availability of gas, a number of expansion projects were taken up in the last few years with naphtha as feedstock with the flexibility for switching over to gas as and when it is available. Feasibility of a delivery system of Liquefied Natural Gas (LNG) to meet the demand of fertilizer units and projects is also being explored.

To encourage investment in the fertilizer sector, the government has allowed the following concessions to the domestic industry:

- Concessional customs duty benefit on import of capital goods for setting up of new plants / substantial expansion / renovation / modernization of existing units
- Deemed export benefits to indigenous supplies of capital goods to new / revamped / retrofit / modernization of fertilizer projects, provided such supplies are made under the procedure of international competitive bidding and no price preference is given to indigenous vendors.

Fertilizer projects now under implementation in the country would add a capacity of 0.5 MMTPA of urea. An 'in principle' approval has also been given to the following four projects for urea capacity creation (3.07 MMTPA)

- Hazira Expansion Project of KRIBHCO at Hazira, Gujarat
- Thal Expansion Project of RCF at Thal, Maharashtra
- Gorakhpur Project of KRIBHCO at the site of FCI's old plant at Gorakhpur, UP
- iv)Nellore Grassroots Project of IFFCO at Nellore, Andhra Pradesh

The initiatives undertaken to set up joint venture projects in countries with better resource endowments so as to meet the growing demand of fertilizers in the country have made significant progress. The Government has approved the investment of NFL/KRIBHCO to make an equity contribution of US$ 69 million each in a joint venture in Oman for production of 14.52 lakh tonnes of urea and 3.30 lakh tonnes of merchant ammonia per annum. The Joint Venture Company i.e. Oman India Fertilizer Company has been registered in Oman on 18.2.1998. However, primarily on account of the continuous and significant dip in the international market, the project proposal is being revised and restructured. The revised proposal is being processed for obtaining the approval of the Government.

The Fertiliser Association of India has estimated that the consumption of urea would go up to 48 million tonnes in 2012. Since reliance on imports would have to be limited, additional capacity of nearly 20 million tonnes would be necessary. The feedstock policy for nitrogenous fertilizers had hitherto envisaged establishment of new plants based mainly on natural gas. However, in view of the abundance of coal in the country, the government has set up an expert committee to report on the feasibility of setting up new plants based on coal.

Realizing the constraints in the availability of natural gas which is the preferred feedstock, Department of Fertilizers has set up a Core Group of

Fertilizer Companies with a view to exploring the feasibility of importing LNG by forming a consortium of fertilizer companies, along with other interested economic operators, for fertilizer sector in particular and other complementary sectors such as power, domestic fuel etc. The report of the Core Group is being processed by the Government.

One of the options being considered envisages the installation of a re-gasification facility at Kishorprasad in Orissa and the construction of a pipeline connecting the fertilizer plants in the eastern sector with an inter-link to the HBJ pipeline. Existing naphtha based units such as IFFCO-Phulpur, DIL-Kanpur, Nangal, Panipat and Bhatinda units of NFL and new projects like KRIBHCO-Gorakhpur could also be served by this system.

Unconventional sources of gas

Underground Coal Gasification (UCG)

India has vast coal resources of around 200 billion tonnes and around 24 billion tonnes of lignite. However, the use of coal for primary energy generation in India in the coming days will have to reckon with the following factors:

- Coal is not a clean fuel. Burning coal generates solid waste, harmful emissions as well as greenhouse gases.
- More than half of the coal and lignite resources lie at such depths that these are not mineable.
- This coal can be utilised through non-conventional means like underground coal gasification (UCG).

In this process, air or oxygen along with steam is injected into the coal seam where the oxidants sustain a reaction zone that moves along the seam where the coal is dried, pyrolysed, combusted and gasified. The product is called syngas, which is a mixture of CO, CO_2, H_2, CH_4, and N_2. This medium-btu gas can be used for power generation and can also be the feedstock in the manufacture of methanol/gasoline etc. Further, the gas may be economically transportable over 200-300 kms through pipelines.

The British and the Russians have conducted the largest UCG program. The only operating UCG project is in the Angnen coal mine in Uzebekistan. TheEnergy Research Development Administration (ERDA) of USA has undertaken a number of UCG pilot tests through the joint efforts of the industry, research institutes and government agencies. In 1996, the US congress enacted a law directing the energy secretary to promote UCG for the US energy markets.

Feasibility studies and preliminary testing for UCG has been reported from other countries such as Spain, Belgium, Germany, Brazil, North Korea, Canada and India. In India, UCG was taken up as a National Project in the 80's for 3 regions associating relevant scientific research institutes and the industry. Extensive work was done in collecting resource information in Gujarat, Rajasthan and Bihar. Further UCG work remains deferred due to doubts of surface subsidence, groundwater contamination and other environmental factors. GAIL has now proposed a detailed feasibility study to assess the potential of exploiting deep seated lignite (within a depth range of 800m) deposits in Rajasthan through the in-situ gasification technology.

Gas hydrates

Exploration for gas hydrates

At present, gas from hydrates is being produced only in Russia but both USA and Japan have taken up projects for development of gas production from hydrates. Methane from Hydrates is being produced at the Western Siberian Messoyakhskoye conventional gas field. The process involves depressurization and injection of methyl alcohol. The gas-producing zone is at a depth of 870 metres (2,900 feet). The hydrate zone ranges from 250 metres (820 feet) to 870 metres (2,900 feet).

- The U.S.DOE had a very active hydrate R&D programme in the 1980s. Currently, the bulk of hydrate activity in the U.S. is centered on assessment of hydrate resources in Alaska. JNOC of Japan is exploring an accumulation of methane hydrates in offshore Japan, north of Hokkaido along Japan's eastern coast. This is estimated to hold over 200 TCF of gas. MITI is seeking to establish whether hydrates could be a commercial gas source in the 21st Century and lower Japan's dependence on imported LNG. JNOC has drilled the first test wells and would now begin development of advanced production technologies. The estimated expenditure on the program is $85 to $ 90 million. The steps necessary for commercial production of gas from gas hydrates are:
    - Identify areas most prospective for gas/gas hydrates in India's Continental Shelf based on Existing Geological and Geophysical information.
    - Carry out regional/detailed seismic surveys for pin pointing 3 to 5 drillable prospects.
    - Determine Ground Truth – Shallow Core Drilling
    - Drilling and Production Testing

- Reservoir Modeling and Simulation
- Scoping Study – A conceptual study involving all phases of production from gas hydrates based on existing knowledge and technology.
- Design and Construction of Deep Water Production System.

A certain minimum amount of research and development would be necessary in all the above areas to initiate the program and continuous input in R&D would be necessary to sustain the program till commercial production is obtained.

The National Gas Hydrate Program for India proposed by the ninth plan working group would involve an outlay of around Rs. 213 crores in the following phases:

Stage	Activities	Cost (Rs. Crore)
Phase – I	Examine existing Geological, Geophysical data	10
Phase – II	Acquisition and processing of seismic data	38
Phase – III	Stratigraphic drilling, coring 3-5 wells.	15
Phase – IV	Drilling and completion of 3-5 wells	150

It is only by bringing together a large number of companies, research institutes, universities and consultants that we may succeed in this program, which involves high risks and large outlays.

Based on their examination of existing multi-channel seismic data, ONGC has arrived to the following tentative conclusions:

- About 80,000 sq.kms. area is found to be favourable for the presence of Gas Hydrate.
- Fore Arc basin of Andamna-Nicobar Offshore is considered to be most prospective for gas hydrates due to presence of very good seismic attributes in favourable geological set up.
- Krishna-Godavari offshore and Kachchh offshore are good locations for gas hydrate formation.

ONGC has also prepared a map showing the "Relative Prospectivity" of potential hydrate bearing areas. ONGC is planning to undertake acquisition of fresh seismic data in offshore Krishna-Godavari area for detection of gas hydrates.

GAIL has identified approximately 64000 sq km in offshore Goa and applied for an exploration license with a view to acquisition, processing and interpretation of seismic data, sample collection of gas hydrates and drilling of 2-3 wells.

Strategic alliances in the hydrocarbon sector

Meeting the fast expanding need for oil and gas in India would call for a number of alliances at the company level as well as at the level of governments. The objectives behind such alliances would be the acquisition of latest technologies, which may not be available commercially for years to come and also to mobilize the necessary finances for developing the hydrocarbon industry. Policy reforms have already been initiated in the sector to attract private and international capital. In addition, India has to forge linkages with large investors. Exploration and production of oil and gas would increasingly take place in difficult areas including deep waters. Subsea pipelines would have to be laid at water depths exceeding 3000 mtrs to bring gas from the Middle East. Unconventional gas sources like CBM and Hydrates will need to be tapped for the next century. The technologies in these areas would be available to India only to the extent that India participates in their development and this has to be done in partnerships with the leading countries/companies. The partnership of GAIL and IOC with BP and Amoco for the production of DME is an example of such alliances. The areas where these initiatives are needed and the possible partnerships that may be developed are discussed below.

Gas hydrates

A number of hydrate deposits have been located off the eastern and the western coasts of India. However, the technology of tapping the methane in these deposits is yet to be proved. Both USA and Japan have taken up projects for gas production from hydrates. The USDOE has an active hydrates program centered on the hydrate deposits in Alaska. In Japan, the Natural Resources and Energy Agency of MITI plans to explore deposits north of Hokkaido along the East Coast. JNOC has completed the first test well at 850 mtrs. water depth.

Hydrates can block deep sea pipelines. Research on hydrates would help R&D on laying and operating these pipelines. Hydrates may also offer new methods of transporting gas in a cheaper and easier way than as LNG. The Indian National Hydrates Program may benefit from collaborating with Japan and USA. Preliminary contacts show that these countries would be willing to collaborate with India.

Deep sea pipelines

The feasibility study for the Oman-India pipeline was attempted by the Oman Oil Company in 1995. The attempt was not successful. Deep water technology has made much progress since then. It is estimated that an expenditure of around USD 50 million is required to be spent on developing the technology. GAIL should take the lead in forming a consortium for collaborative research into this problem. The participation of Gazprom of Russia will be valuable for the project. Gazprom is venturing into a deepwater gas pipeline from Russia to Turkey.

An LNG buyers forum

Japan, Korea and Taiwan are the LNG users in Asia at present. India is joining the club soon. LNG contracts have all along been individually negotiated and exchange of information has been restricted because of confidentiality conditions in the contracts. This has favoured the LNG suppliers. An alliance between the major consumers would help in making the LNG market more user friendly. Collaboration is also possible in reducing the incidence of take-or-pay obligations through exchange of shipments. The consortium may also encourage research in the development of technology.

Transit agreements for international gas pipelines

Asia as a whole is heavily dependent on import of oil from the Middle East. The dependence is increasing. The idea of an Asian gas grid has been floated to provide an alternative to oil by bringing gas from the Middle East, central Asia and the Russian Far East to Asian consumers. In India, gas pipelines from Iran and Turkmenistan could conveniently pass through Pakistan if the question of security of supplies could be satisfactorily addressed. Europe has by and large solved this problem although there have been problems, such as between Russia and Ukraine. An Asian energy charter on the lines of the European Energy Charter may help us with many of these problems. The Charter is required to promote a consensus on the central objectives of energy policy, such as energy saving, diversification of supplies, integration of networks and environmental conservation and to create a political, legal and financial instrument to include substantial transfers of capital, management expertise and technology. Japan has been an enthusiastic proponent of this idea.

Exploration in Central Asia

The vast oil and gas reserves of Kazakhstan, Turkmenistan and other central Asian countries can provide a long-term alternative to the Middle East. USA, Russia and China are all active in the region. India has rightly taken interest in these countries and a number of high level delegations have visited the area recently. India's interest in this area is closely allied with that of Russia and this should be consolidated through government/company level ties.

Gas imports from Iran

Iran is extremely important for India. Iran provides both a possible source of gas and the best access to the gas/oil reserves of central Asia. India has excellent relations with Iran but efforts towards the import of gas from Iran have been hindered by the US sanctions against Iran. This makes it imperative for India to play a lead role in persuading USA to rethink her Iran policy.

Gas imports from Bangladesh and Myanmar

In view of the geo-political difficulties in the import of gas from the Middle East, the gas reserves in our eastern neighbourhood become important to India. Myanmar has had initial success in the exploration of her offshore reserves. Bangladesh has an active exploration program and a large potential. Unocal and Shell have emerged as the most important players in this region. The Government of India has long been convinced that cooperation in the field of energy, in particular natural gas, with India's two eastern neighbours – Bangladesh and Myanmar – would be of long term mutual benefit. The specific areas involved would include the following:

- exploration
- import through pipeline
- Indian investment in the manufacture of value-added products such as power or fertilizers with buy-back arrangements

The Government of India has conveyed its views to the Governments of the respective countries and regularly engaged them in discussion on the subject. The Government has also encouraged Indian companies including GAIL, ONGC, Indian Oil, NTPC and BHEL to interact commercially in both countries in this connection.

India has indicated to the Bangladesh Government that it is willing to consider import of natural gas or gas-based products from Bangladesh. India has pointed out that this would result in an increase in Bangladesh's exports to India and thus help to narrow the trade imbalance about which Bangladesh has often expressed concern. India has been given to understand that the policy of the Bangladesh Government does not currently permit export of natural gas to India as Bangladesh's requirements first need to be met. Bangladesh has also stated that it needs to satisfy itself about the extent of its reserves before exports can be considered.

The Myanmar Government has conveyed its interest in selling natural gas to India and in India's involvement in its exploration programme. The Government of India is positively inclined to progress in this area of cooperation between the two countries. A delegation representing GAIL, ONGC and Indian Oil visited Myanmar in July 1997 to assess the potential for Indian participation in the natural gas sector.